

Article

On-Line Insulation Monitoring Method of Substation Power Cable Based on Distributed Current Principal Component Analysis

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Abstract: Monitoring the insulation condition of power cables is essential for ensuring the safe and stable operation of the substation power supply system. Leakage current is an important indicator of insulation performance of power cables. However, the application of leakage current monitoring methods in substations is limited due to issues such as neutral line shunting on the load side and the spatial isolation of the phase-to-neutral line in the power cabinet. This paper proposes an insulation monitoring method based on distributed current principal component analysis for power cables in substations. Firstly, the leakage current of substation power cable is measured by a distributed current extraction method, and the cable insulation condition is preliminarily judged. Then, considering the problem of measurement error interference in the process of distributed current synthesis, an evaluation method of power cable insulation state based on principal component analysis of distributed current is proposed. To verify the feasibility of the proposed method, both simulation and laboratory tests were conducted. The results indicate that the proposed method can effectively measure the leakage current of power cables in substations and realize the accurate distinction between measurement error and cable insulation degradation characteristics. The method offers a novel idea for insulation monitoring of substation power cables.

Keywords: segmented current extraction; insulation monitoring; principal component analysis; leakage current; substation



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1. Introduction

The power cable in a substation transmits electrical energy throughout the entire system. Ensuring its proper insulation is crucial for maintaining stable operation of the substation [1]. On the one hand, as the working years increase, the power cables of the substation power system are easily deteriorated due to the harsh working environment and voltage stress. This will hinder the normal transmission of electric energy and even cause fires in serious cases [2–4]. Therefore, it is very important to carry out research on power cable insulation monitoring methods suitable for substations [5,6].

Since off-line cable insulation assessments consume significant financial and human resources, and certain critical loads in the substation power supply system cannot be powered off, on-line insulation monitoring is more suitable [7,8]. To enable real-time monitoring of cable insulation status, many researchers have proposed various methods, including partial discharge (PD) signal measurement, AC superposition, DC superposition,

dielectric parameter measurement, and leakage current measurement [9]. These methods offer effective ways to assess insulation conditions without interrupting power supply to critical systems.

Among these methods, the on-line partial discharge (PD) signal method diagnoses the insulation status of cables by measuring high-frequency signals generated during partial discharge events in the cable insulation. However, these signals often overlap with external noise, requiring advanced signal processing techniques. Additionally, there is a lack of standardized and scientific evaluation criteria [10].

The AC superposition method involves applying an AC voltage of a specific frequency to the cable shielding layer and detecting a characteristic current signal at 1 Hz, which indicates the aging of the cable. This method was first introduced by Japanese scientist Takao Kumazawa [11]. However, in operational substations, it is challenging to measure such a small signal due to strong interference.

The DC superposition method injects a low-voltage source at the neutral point and uses a high-sensitivity ammeter to measure the leakage current or insulation resistance through the cable insulation layer. This method is only suitable for systems with ungrounded neutral points on the load side. Additionally, it measures only the overall insulation resistance of the line while neglecting distributed capacitance information, which hinders a comprehensive assessment of the cable's insulation condition [12].

The insulation dielectric loss method involves applying voltage to the cable and measuring the current flowing through the insulation layer via a voltage transformer and a current transformer [13,14]. The insulation loss factor ($\tan \delta$) is then calculated to determine the cable's insulation quality. However, this method is not applicable to three-phase cables laid in substation cable trenches, where high voltages and strong interferences can significantly affect detection. Moreover, the normal dielectric loss factor of cable insulation is typically very small, which makes it prone to interference in the on-line monitoring system [15].

In recent years, the leakage current measurement method has gained attention due to its strong resistance to electromagnetic interference and its ability to provide quantitative assessments [16,17]. However, in substation power supply systems, challenges such as neutral line shunting on the load side and phase-to-neutral line isolation within power cabinets complicate leakage current measurements. Furthermore, since the leakage current is typically at the milliamper (mA) level, reducing sensor error interference and improving measurement accuracy are critical issues for applying this method to insulation monitoring of substation power cables.

In response to the aforementioned challenges, this paper proposes an on-line leakage current monitoring method for substation power supply systems. The main contributions are as follows:

- (1) A method for on-line monitoring of leakage current in substation power supply systems based on distributed current measurement is proposed. The proposed method can solve the issue that the leakage current cannot be directly measured due to the neutral line shunting on the load side and the separation of the phase line and neutral line in the power cabinet.
- (2) A mathematical model of the leakage current distribution of power cables in substations is established, and the main factors of leakage current changes in substations are analyzed.
- (3) A method for evaluating the deterioration state of power cables in substations based on the principal component analysis method was proposed. This method can reduce false alarms caused by sensor errors when the unbalanced current is large and accurately judge the deterioration of cable insulation.

The rest of this paper is organized as follows. The leakage current monitoring method of substation power cable based on distributed current extraction is introduced in Section 2. The power cable insulation monitoring method and process based on principal component analysis are proposed in Section 3. In Section 4, the proposed method is simulated and verified. In Section 5, the laboratory test is carried out to further prove the applicability of the method. The last part summarizes the contribution of this paper.

2. Leakage Current Measurement Method of Substation Power Cable Based on Distributed Current Extraction

2.1. Cable Insulation Aging Characteristics

The aging process of cables often results in parameter changes [18,19]. Taking the power cables commonly used in the three-phase power supply circuit of a substation as an example, the equivalent distributed parameter model of the cables in the transmission line is shown in Figure 1a.

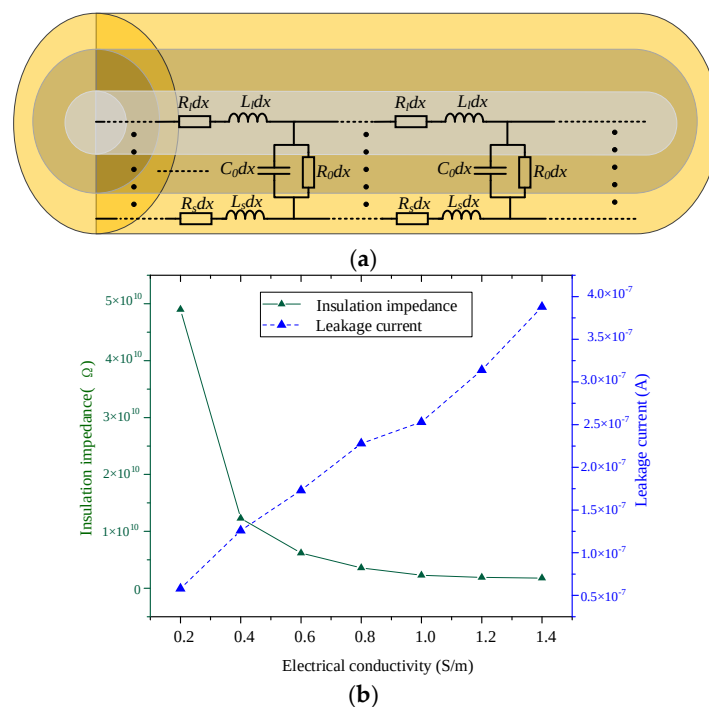


Figure 1. (a) Distributed parameter model of power cables. (b) Leakage current and insulation impedance change curve during aging process.

In Figure 1a, R_l and L_l are the equivalent resistance and inductance per unit length of the power cable conductor core. R_s and L_s are the equivalent resistance and inductance of the unit length of the sheath layer. R_0 and C_0 are the insulation resistance and distributed capacitance per unit length of the power cable. Their specific values can be calculated from the actual component materials, dimensions, structure, and other parameters of the cable. The calculation formulas for the insulation conductance G_0 and capacitance C_0 per unit length are shown in Formulas (1) and (2).

$$G_0 = f \frac{4\pi^2}{\ln(r_i/r_w)} \epsilon_0 \epsilon_r' \quad (1)$$

$$C_0 = \frac{2\pi}{\ln(r_i/r_w)} \epsilon_0 \epsilon_r \quad (2)$$

where f represents the operating frequency, r_i is the cable conductor radius, r_w is the cable insulation radius, ε_0 is the dielectric constant in a vacuum, ε_r is the relative dielectric constant of the insulation capacitance, ε'_r is the relative dielectric constant of the insulation conductivity. During the aging process of the cable, its aging products accumulate in the cable insulation layer, affecting the molecular dipole moment of the insulation material, resulting in an increase in the dielectric constant and ultimately leading to an increase in the distributed capacitance C_0 and insulation conductance G_0 .

As the aging process continues, cable leakage current and insulation resistance values vary with the dielectric constant, as shown in Figure 1b. During the degradation of cable insulation, due to the change in the dielectric properties of the insulation material, the distributed capacitance of the cable continues to increase, the insulation resistance continues to decrease, and the leakage current continues to increase, which makes it feasible to monitor the cable insulation status based on the leakage current measurement.

2.2. Leakage Current Distribution Model of Power Cable in Substation

The cable leakage current monitoring model of the substation power supply system is shown in Figure 2. This part will analyze the constructed leakage current mathematical model.

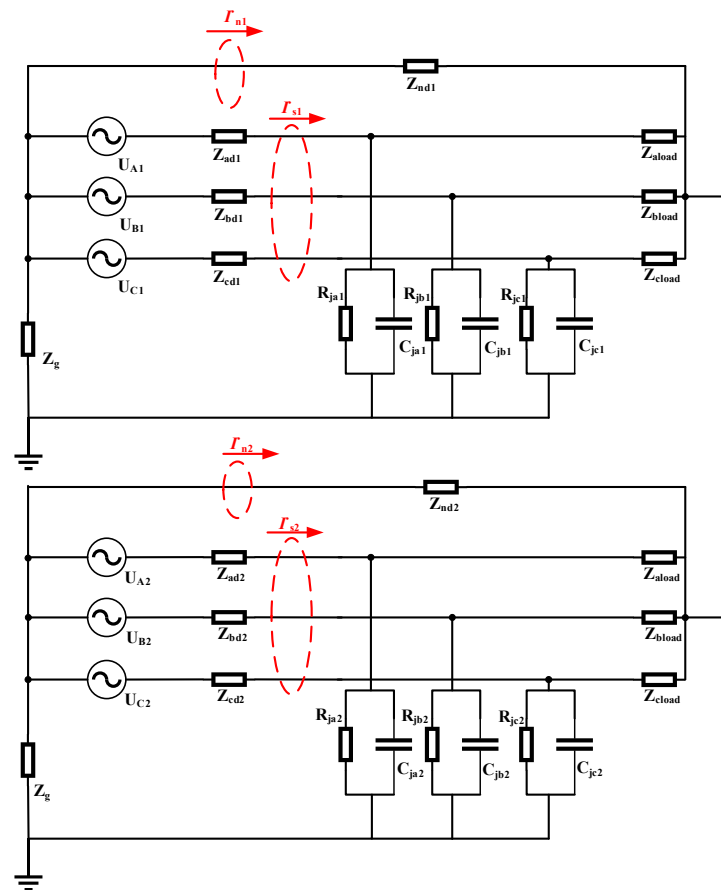


Figure 2. Parameter model of AC leakage current for substation cable.

Figure 2 is the equivalent circuit diagram of cable leakage current monitoring in the substation power supply system. In order to simplify the analysis, the shielding layer and sheath layer in the cable model are not considered here. In Figure 2, U_A , U_B , and U_C are 220 V three-phase power supplies. Z_g is substation grounding impedance, usually less than 4Ω . Z_{ad} , Z_{bd} , Z_{cd} , and Z_{nd} are the impedances of the three-phase and N cable lines. The insulation resistance of the three-phase cable is $R_{ja}dx$, $R_{jb}dx$, and $R_{jc}dx$. The distributed capacitance is $C_{ja}dx$, $C_{jb}dx$, and $C_{jc}dx$, Z_{aload} , Z_{bload} , and Z_{cload} are the load impedances. In

actual operating conditions, the distributed parameters of three-phase cables often exhibit a certain degree of asymmetry, which is inevitable. Due to the combined effects of electrical, thermal, chemical, moisture, mechanical stress, and other factors encountered during energy transmission, the insulation level of three-phase cables gradually deteriorates to varying extents. This leads to an increase in the imbalance of the three-phase insulation. The asymmetry of the distributed parameters in transmission lines typically ranges from 0.5% to 3.5% [20]. The asymmetry denoted as ρ_i , for transmission line i , is defined as:

$$\rho_i = \frac{k_{0i}}{Y_i} = \frac{Y_A + \alpha^2 Y_B + \alpha Y_C}{Y_A + Y_B + Y_C} \quad (3)$$

where Y_i is the three-phase distributed total admittance of line i . k_{0i} is the asymmetric vector sum of line i to ground parameters. Y_A , Y_B , and Y_C represent the three-phase admittance of line i . $\alpha = e^{j2\pi/3}$ is the rotation coefficient. For the sake of simplicity, the power supply of power source 1 is taken as an example. Since the power supply system in the substation is a load-side neutral point ungrounded system, the measured leakage current value I_{leakage} should be as shown in Formula (4):

$$I_{\text{leakage}} = U_1 \cdot \rho_1 \cdot (Y_{ja} + Y_{jb} + Y_{jc}) \quad (4)$$

It is important to note that in substation power supply systems, the imbalance of the distribution load is directly related to the size of the load, and it is often difficult to calculate or predict. The imbalance in the distributed parameters of three-phase cables typically remains stable from the beginning of the cable's operation, when it is in good condition, through its degradation process, unless a special fault occurs. When a major fault takes place in one of the phase lines, the imbalance will increase significantly. As a result, leakage current monitoring in the substation AC power supply system can effectively reflect changes in cable insulation resistance and distributed capacitance, thus providing insights into the degradation state of the cable. By measuring the vector sum of the unbalanced current and the N-line current, a weak leakage current signal can be extracted from the larger load current. This leakage current signal is proportional to the line admittance. The vector sum of the currents at the four sampling nodes in Figure 2 must satisfy Equation (5).

$$\dot{I}_{s1} + \dot{I}_{n1} + \dot{I}_{s2} + \dot{I}_{n2} + \dot{I}_{\text{leakage}} = 0 \quad (5)$$

where $\dot{I}_{s1}$, $\dot{I}_{s2}$ are the unbalanced currents of the main and backup power supplies, $\dot{I}_{n1}$ and $\dot{I}_{n2}$ the N-line currents of the main and backup power supplies, respectively. Let the current vector sum of the four sampling nodes be $\dot{I}_{\text{sum}}$. Therefore, the cable insulation aging can be monitored by calculating the current vector sum of the four sampling nodes $\dot{I}_{\text{sum}}$ and judging whether the value exceeds the set empirical threshold T_I .

2.3. Substation Power Cable Leakage Current Monitoring Method Based on Distributed Current Extraction

From the above analysis, it is clear that the aging characteristics of cables can be effectively characterized by the leakage current value. Wu measured the leakage current by injecting a common-mode voltage of a specific frequency into the neutral point of the transformer [21]. However, since the main and backup power supplies of the substation power system share the same neutral line (as shown in Figure 3), this approach is not suitable for practical application. The main challenge faced by current cable insulation monitoring methods based on leakage current measurement is the difficulty in extracting the small leakage current, which is often overshadowed by the much larger load current. This paper proposes a leakage current monitoring method based on distributed current

extraction, which involves measuring the phase current and neutral line current for both the main and backup power supplies of the substation power system. By synthesizing and analyzing the collected currents from each node, the total leakage current value can be obtained. This synthesized current provides a more accurate representation of the cable's degradation state.

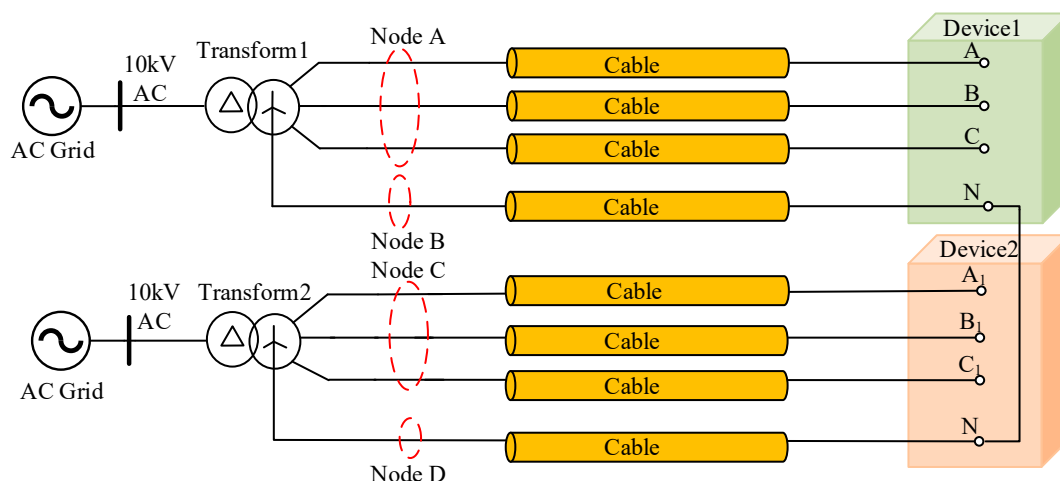


Figure 3. Block diagram of a dual-supply AC power system in substation.

As shown in Figure 3, the bus voltage is stepped down by transformer #1 and transformer #2 in the substation to obtain two power supply voltages. The two power supply voltages are distributed by two distribution cabinets and then transmitted to the cooling, control, and other loads in the substation through the cables laid in the substation cable trench. In general, only one of the two power supplies is turned on (assuming it is the main power supply #1). In this case, the main power supply forms a current loop with the neutral line of the main power supply and also forms a loop with the neutral line of the backup power supply. At this time, the composite current value of nodes A, B, C, and D can be measured to obtain the insulation status of the feeder line cable. This method has the following advantages:

- (1) Compared with other leakage current measurement methods, this method does not require any current injection and does not affect the normal operation of the circuit.
- (2) This method can measure the overall insulation state of the line cable. The total leakage current value also contains information on distributed capacitance and insulation resistance. It can evaluate the insulation state of the line as a whole and ensure the accuracy of the measurement.
- (3) The leakage current measurement device used in this method is different from other leakage current measurement methods. The measurement device in this method measures the load current with a large value, while avoiding the challenges in measuring weak leakage currents. This approach reduces the difficulty associated with measuring small leakage currents and ensures more reliable and consistent data collection.

The proposed distributed current extraction method for measuring the leakage current of power cables in substations can make a preliminary judgment on the insulation degradation of power cables in substations by synthesizing the distributed currents at different measuring points to obtain leakage current information. In the next section, in order to avoid the interference of sensor errors during the synthesis process, the principal component analysis method is used to separate the power cable degradation characteristics and perform insulation monitoring of power cables in substations without error interference.

3. Power Cable Insulation Monitoring Method Based on Principal Component Analysis

In the process of distributed current extraction, since the synthesized leakage current is only at the mA level, when the single-node measured current is large, the measurement error introduced by the sensor has a serious impact. To address this problem, this paper proposes a distributed current principal component analysis method for substation power cable insulation status monitoring. Through the distributed current extraction method, secondary current information that can reflect the line operation status is obtained [22]. Under the constraint of the short-term invariant characteristics of the leakage current signal, combined with the acquired information, the statistical analysis method can be used to perform an error-free evaluation of the line insulation degradation status and evaluate the measurement error of each node sensor.

The four leakage current collection nodes set are represented as $A_j, j = 1, 2, 3, 4$. The current data from the four nodes were used to construct a sample matrix $X \in \mathbb{R}^{m \times 4}$. Based on the PCA principle, the normalized data matrix A of sample matrix X can be decomposed as follows:

$$A = \hat{A} + E = TP^T + T_e P_e^T \quad (6)$$

where $\hat{A} = TP^T$ is a principal subspace model of data matrix A , which contains the main change information of the primary current signal. $E = T_e P_e^T$ is a residual subspace model of data matrix A , which contains the measured noise information of the residual space of the sample matrix. T is the principal score matrix, P is the principal load matrix, T_e is the residual score matrix, and P_e is the residual load matrix [23].

The load matrices P and P_e can be obtained by decomposing the singular values of the covariance matrix R of the data matrix A , as shown in the following Equation (7):

$$R = A^T A / (n - 1) = [PP_e] \Lambda [PP_e]^T \quad (7)$$

where $\Lambda = \text{diag}(\lambda_1, \lambda_2, \lambda_3, \lambda_4)$, $\lambda_1 \geq \lambda_2 \geq \lambda_3 \geq \lambda_4$ is the eigenvalue of the covariance matrix R . $[P \ P_e]$ is a load vector composed of its corresponding eigenvector. The larger the eigenvalue, the more relevant the variable represented. The variance interpretation for each principal component can be refined as Equation (8):

$$VE_{P_i} = \frac{\text{Var}[P_i]}{\sum_{j=1}^M \text{Var}[P_j]} \quad (8)$$

where $\text{Var}[P_i]$ is the variance of the principal component i . By calculating the principal components, the variances are arranged in a decreasing trend, and the first principal component has the highest variance. The number of principal components in the principal component subspace is calculated by the cumulative percent variance (CPV) method. The cumulative sum of the variance contributions of all principal components is greater than the preset value of 85%.

When there is a problem with the insulation state of the cable, the projection of the measured data onto the principal component subspace will deviate to some extent. Similarly, when the measurement error is large, the projection of the measurement data on the residual subspace will also be biased. Hotelling's T^2 statistic can be established in the principal component subspace to assess the degree of deviation of the principal components, while the Q statistic can be established in the residual subspace to evaluate the degree of deviation of the residuals in the data. Hotelling's T^2 statistic and Q statistic are described as below.

(a) Hotelling's T^2 statistic

Hotelling's T^2 is the standard sum of squares of the score phasor, which is mainly used to measure the information size of the measurement data projected into the principal element subspace. The specific expression is as follows:

$$T^2 = A^T P \Lambda^{-1} P^T A = \sum_{i=1}^p \frac{t_i^2}{\lambda_i} \sim \frac{p(n^2 - 1)}{n(n - p)} F(n, n - p) \quad (9)$$

where p is the number of principal components, $F(n, n - p)$ is the F distribution with n and $n - p$ degrees of freedom and given the confidence level α . The control limits of Hotelling's T^2 statistic are shown in Equation (10).

$$T_\alpha^2 = \frac{a(n^2 - 1)}{n(n - a)} F_\alpha(\alpha, n - \alpha) \quad (10)$$

Since the T^2 statistic only contains the principal component score information, it reflects changes in principal component information (information about cable degradation in distributed current data).

(b) Q statistic

The abnormal changes in information that are not projected into the principal component subspace can be judged by calculating the Q statistic in the residual subspace. The specific expression of the Q statistic is as follows.

$$Q = (X P_e P_e^T) (X P_e P_e^T)^T = X P_e P_e^T X^T \leq Q_c \quad (11)$$

where Q_α is the statistical control threshold with a significance level of α , which can be calculated as follows.

$$Q_\alpha = \theta_1 \left[\frac{C_\alpha \sqrt{2\theta_2 h_0^2}}{\theta_1} + 1 + \frac{\theta_2 h_0 (h_0 - 1)}{\theta_1^2} \right]^{\frac{1}{h_0}} \quad (12)$$

In the formula, $\theta_i = \sum_{j=\alpha+1}^4 \lambda_j^i$ ($i = 1, 2, 3, 4$), $h_0 = 1 - 2\theta_1\theta_3/3\theta_2^2$, C_α is the critical value of the normal distribution at the detection level α .

However, the threshold determination based on Equations (10) and (12) assumes that all score vectors are independent and identically distributed Gaussian variables. In practice, the score vectors obtained after PCA decomposition do not strictly follow a normal distribution. In such cases, kernel density estimation (KDE), a non-parametric method, can be used to calculate the statistical control limits [24].

According to Formulas (9) and (11), the T^2 statistic and Q statistic of the data matrix are calculated as $T^2 = [T_1, T_2, \dots, T_m]$ and $Q = [Q_1, Q_2, \dots, Q_m]$, respectively. Kernel density estimation can estimate the probability density distribution of a statistic without any assumptions, relying only on the probability density distribution of the statistic.

Taking the T^2 statistic as an example, $T^2 = [T_1, T_2, \dots, T_m]$ is the sampling points of independent and identically distributed F, and the probability density function of F is $f(T)$. Then the kernel density estimate of $f(T)$ at any point T is Formula (13).

$$\hat{f}(T) = \frac{1}{mh} \sum_{i=1}^p N\left(\frac{T - T_i}{h}\right) \quad (13)$$

where N is a Gaussian function as a kernel function, and h is a smooth parameter. Then we can obtain the probability density function of the statistic.

$$F(x) = \int_{-\infty}^x \hat{f}(x) dx \quad (14)$$

Furthermore, the upper and lower thresholds x_1 and x_2 of the statistic can be obtained by setting the effective levels α and β .

$$\begin{cases} x_1 = F^{-1}(1 - \alpha) \\ x_2 = F^{-1}(1 - \beta) \end{cases} \quad (15)$$

When the monitored Q statistic exceeds the control limit, the contribution rate Q_i of the current data I_i measured at the i -th node to the statistic Q is calculated using Formula (15).

$$Q_i = (M_i - \hat{M}_i)^2 \quad (16)$$

where M_i is the column vector of the measurement data matrix and $\hat{M}_i$ is the column vector corresponding to the principal subspace data matrix. By counting the nodes with the largest contribution rate, the sensor node most related to the fault can be located.

The insulation status assessment process of power cables in substation power supply systems based on principal component analysis is shown in Figure 4.

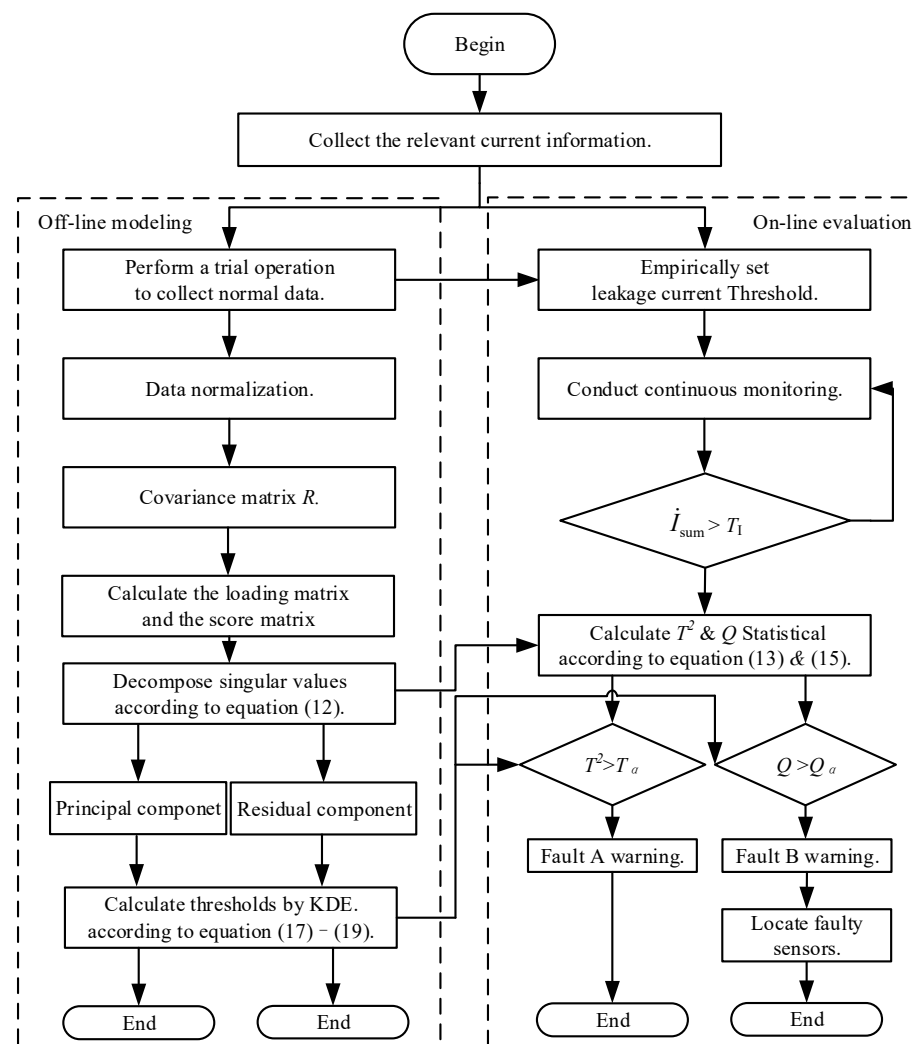


Figure 4. Flowchart of conducting the proposed method in industry applications.

First, install leakage current monitoring sensors at the nodes marked in Figure 3. Collect distributed current information to construct the training set data matrix. Standardize the data matrix to obtain the standardized matrix. Calculate the load matrix and score matrix of the standardized matrix. Then decompose the singular value according to Formula (12) to obtain its eigenvalue and corresponding eigenvector. Select the number of principal components p according to the principle that the cumulative contribution rate is greater than or equal to 85%. At the same time, set the monitoring leakage current threshold T_I according to twice the leakage current when the line is initially operating normally. Then carry out continuous monitoring. Collect distributed current information on-line during the operation period of the power supply system and calculate the composite value. First, determine whether it exceeds the leakage current threshold T_I . If exceeded, calculate the T^2 statistic and Q statistic according to Formula (13) and Formula (15), respectively. And calculate the control limits of the statistic T^2 and Q according to the training set data according to the KDE method. Determine the fault type based on the comparison results of the statistic and the control limit. If the T^2 statistic exceeds the control limit, the cable of this loop is considered to be deteriorated and an alarm is issued. If the Q statistic exceeds the control limit, the measurement error is too large or the sensor is damaged. In addition, the contribution of the Q statistic for each sampling location sensor is calculated to locate the faulty sensor.

4. Simulation Verification

4.1. The Simulation Parameter Setting

Simulation experiments were carried out in Simulink 2022 B software to verify the above analysis. The electrical model of a typical substation power supply system is shown in Figure 4 and is built in Simulink software. The typical substation power supply system low-voltage cable model YJV22-0.6 kV/1 kV is used. “YJV” stands for XLPE insulation, copper core, and PVC sheath, “22” stands for steel tape armor, and “0.6 kV/1 kV” means it is suitable for systems below 0.6 kV and can withstand the highest voltage of 1 kV. The calculation formulas of its distributed parameters during insulation aging are shown in Equations (1) and (2).

The insulation aging process of the cable is mainly reflected in the increase in relative dielectric constant, which is also the main reason for the increase in distributed capacitance and insulation resistance. Figure 5 shows how the relative dielectric constant of the cable changes with different aging degrees.

In order to simulate the deterioration of cable insulation and the increase in measurement error in the substation power supply system, the following processing is performed:

(a) The cable operation status is divided into five types: normal operation, slight degradation, moderate degradation, severe degradation, and damage, and simulation is carried out under different states;

(b) The measurement error is simulated using a white noise module, with the error magnitude controlled by adjusting the noise energy. The error levels are categorized into normal error (0.2%) and interference error (1%);

(c) As shown in Formulas (1) and (2), the cable insulation parameters are determined by the electrical characteristic parameters and the size of the cable conductor and insulation layer. The cable parameters used and other simulation parameters are listed in Table 1.

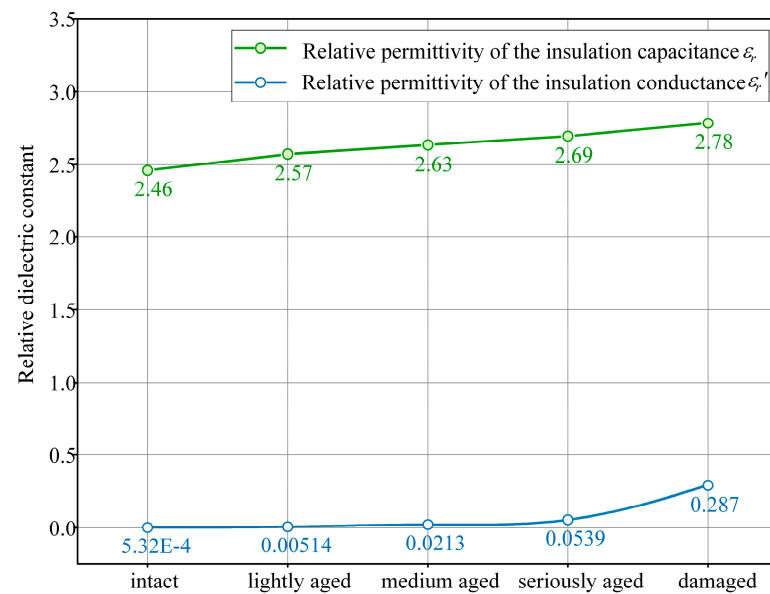


Figure 5. Curve of the relative dielectric constant.

Table 1. Simulation parameter.

Parameter	Values
Conductor radius r_c (mm)	11.68
Insulation radius r_{in} (mm)	18.43
Sheath radius r_s (mm)	20.68
Line length L (m)	500
Effective resistance R_e (Ω /km)	0.67
Distributed capacitance C_d (μ F/km)	0.518
Ground resistor R_G (Ω)	4
Supply voltage U (V)	380 (RMS)
Frequency f (Hz)	50

4.2. Simulation Test of Substation Power Cable Leakage Current Measurement Method Based on Distributed Current Extraction

In order to verify the feasibility of the distributed current extraction method for power cable leakage current, simulation test analysis is carried out on the following two working conditions on the Simulink platform.

CASE I: The measurement error is at a normal level. Under this condition, the changes in the synthetic leakage current for the relevant current are studied, considering different operating conditions of the cable and varying load conditions. The load is categorized into four states: unbalanced large load (70% load imbalance), balanced large load (10% load imbalance), unbalanced small load (70% load imbalance), and balanced small load (10% load imbalance). The load power is 30 kW for the large load and 5 kW for the small load. The synthetic values of the relevant leakage current under these four cable operating conditions are shown in Figure 6.

As shown in Figure 6, when the measurement error is at a normal level, the multi-node composite leakage current $I_{leakage}$ continues to increase as the cable deteriorates. This trend aligns with the theoretical analysis presented in Section 2. Additionally, it can be concluded that the load power and imbalance have minimal impact on the multi-node composite leakage current, demonstrating the robustness of the proposed method.

CASE II: Inaccurate measurement is simulated by increasing the noise energy in the white noise module, with an error of 1%. In real conditions, measurement inaccuracies are usually caused by increased sensor errors. Sensor errors can be caused by a variety

of reasons, such as ambient temperature, poor contact, and electromagnetic interference. As a result, it is unlikely that different sensors at multiple nodes will be inaccurate at the same time. Therefore, this section focuses on scenarios where only one node sensor is misaligned. Using the inaccuracy of the sensor at node one as an example, the variation in the multi-node composite leakage current is studied under different cable operating and load conditions. The composite values of the multi-node leakage current under the four cable operating conditions, with node one sensor being inaccurate, are shown in Figure 7.

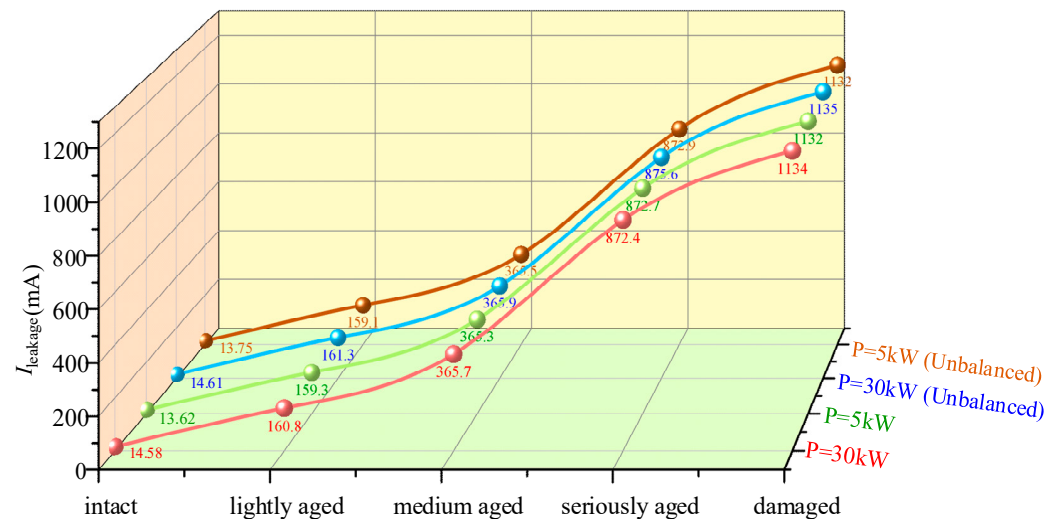


Figure 6. Leakage current situation in CASE I.

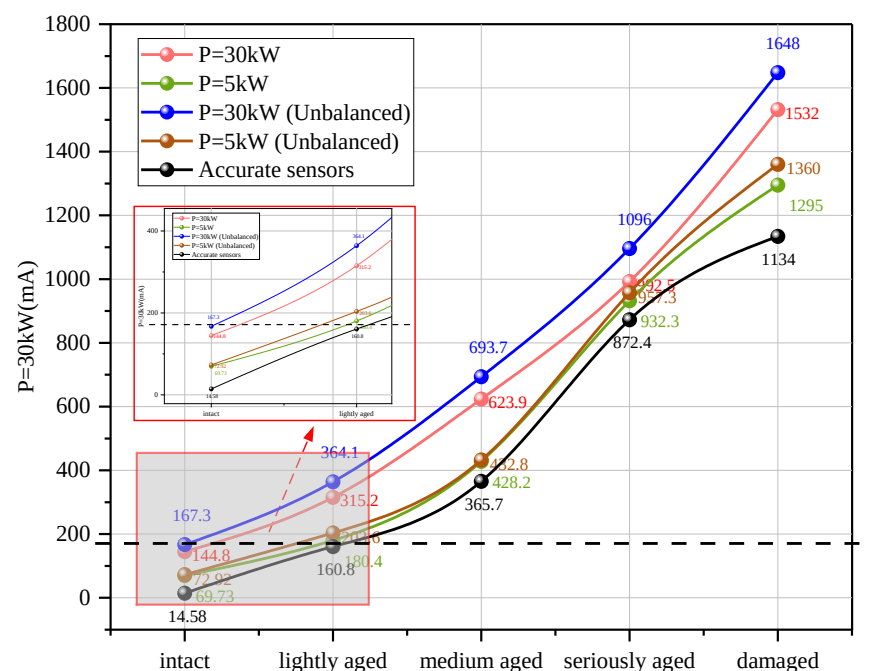


Figure 7. Leakage current situation in CASE II.

Figure 7 shows that when the distributed current measurement is inaccurate, the load level and imbalance have a great influence on the leakage current monitoring. This is due to the superposition of errors when the distributed current signals are synthesized. When the load is large and unbalanced, the distributed current measured by node 1 is higher, and the introduced error is also greater. As can be seen from Figure 7, when the sensor error of the measurement system is normal, the maximum leakage current of the intact cable is only 14.58 mA, and the threshold can be preset to 30 mA. When the cable deteriorates,

the leakage current value increases to 160.8 mA, indicating that the leakage current can reflect the degradation state of the cable. However, when the system introduces inaccurate sensors, even for the intact cable, the maximum leakage current under different working conditions is 167.3 mA, which is far beyond the threshold. Table 2 shows the leakage current information when using normal and inaccurate sensors to measure leakage current with different cable insulation statuses.

Table 2. Leakage current information in different measurement error systems.

Insulation Status	Normal Measurement	Inaccuracy Measurement
Intact	14.58 mA	167.3 mA
Lightly aged	160.8 mA	364.1 mA
Medium aged	365.7 mA	693.7 mA
Seriously aged	872.4 mA	1096 mA
Damaged	1134 mA	1648 mA

4.3. Simulation Test of Power Cable Insulation Status Evaluation Method Based on Distributed Current Principal Component Analysis

According to the above simulation results, when the measurement is inaccurate, the leakage current will increase, making it difficult to distinguish between line cable degradation and measurement error. To address this issue, this section uses the principal component analysis method to distinguish between the increase in leakage current caused by cable degradation and sensor misalignment. The test data were obtained through Simulink simulation. Nine thousand sampling points were selected to form the data set of this model. These data points were collected under a load of 30 kW. Among them, the first 3000 samples are intact cable current data collected by precise sensors to complete the construction of the off-line model. The last 6000 points constitute the test set, which are 3000 current data collected by precise sensors in slightly degraded cable states and 3000 current data collected by inaccurate sensors at node A in the intact cable state. The current data of the three nodes are shown as follows. Since the backup power line is set to be disconnected, the current of node C is approximately 0 and is not displayed.

The distributed current values under the three conditions are shown in Figure 8. At the same time, the main component space Hotelling's T^2 statistic and residual space Q statistic characteristics of the simulation data set under different operating conditions are analyzed, and the results shown in Figure 9. In addition, the thresholds of the main component space Hotelling's T^2 statistic and residual space Q statistic are established through the kernel function.

As can be seen from Figure 9a, although the causes of the faults are different, their leakage current values are not much different, which will bring great problems to the fault detection of substation cables. Figure 9b,c show the Hotelling's T^2 statistic in the principal component space and the Q statistic in the residual space. When the leakage current increases due to a slight cable fault, Hotelling's T^2 statistic in the principal component space obviously exceeds the kernel function threshold. However, when the leakage current increases due to sensor errors, Hotelling's T^2 statistic in the principal component space does not change significantly. Similarly, the Q statistic in the residual space exceeds the threshold only when the mutual inductor is misaligned. Among the 6000 test set samples, the Hotelling's T^2 test accuracy of the principal component space reaches 99%, and the Q test accuracy of the residual space reaches 96%. This proves the effectiveness of the method in this article. In addition, after the Q test in the residual space, the results of Figure 10 can be obtained by testing the contribution rate of the Q statistic.

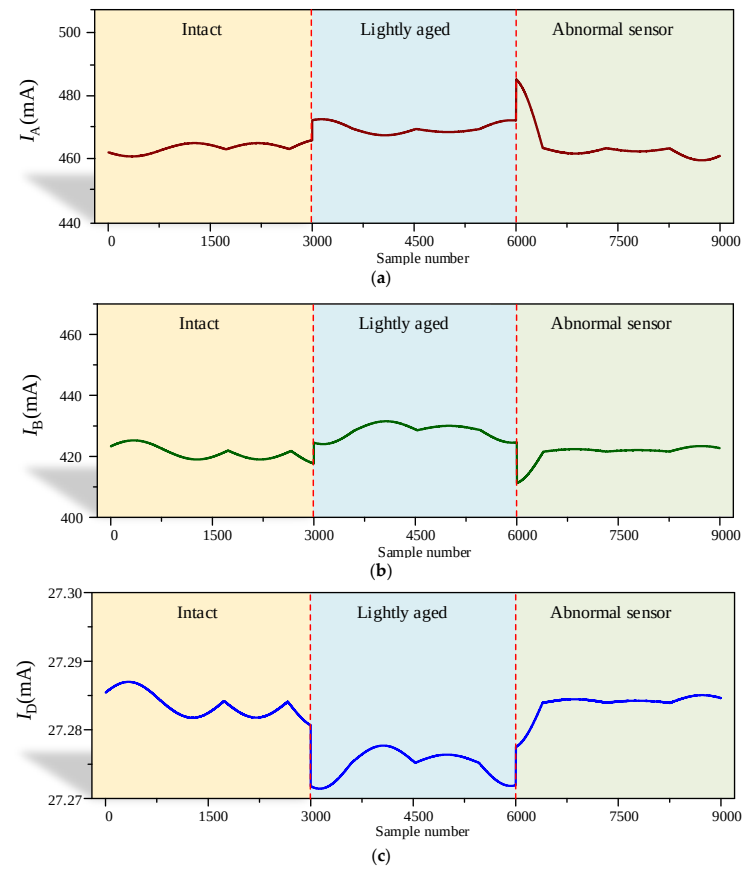


Figure 8. Distributed current of (a) Node A and (b) Node B and (c) Node D.

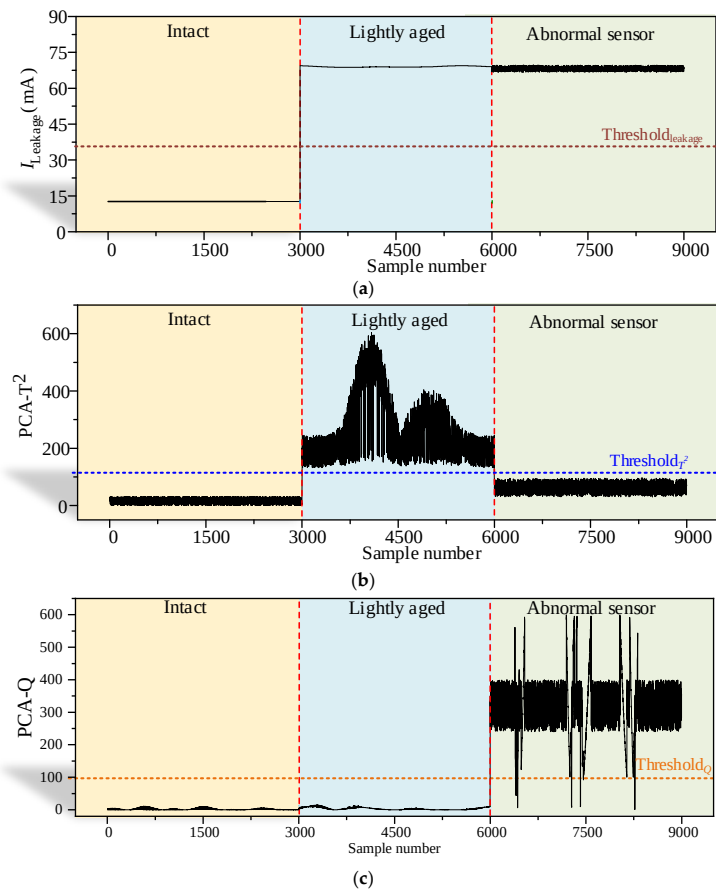


Figure 9. Analysis results of (a) leakage current and (b) T^2 statistic and (c) Q statistic.

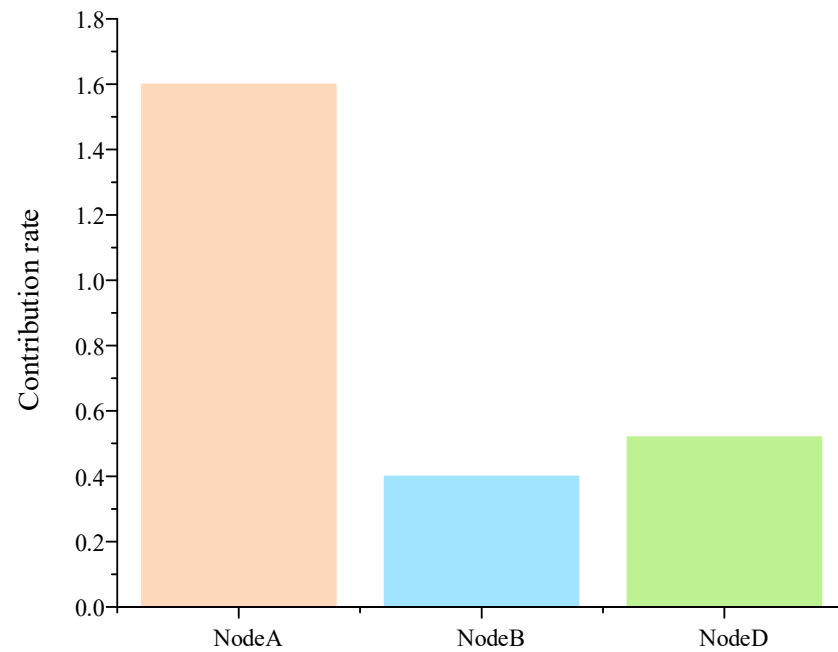


Figure 10. Sensor error contribution plot.

This can lead to the conclusion that the transformer at node A is abnormal, which is the same as the model set in the simulation.

5. Test Verification

5.1. Test Platform Construction

To verify the effectiveness of the method, an experiment was conducted in the laboratory. The actual working conditions of the substation power system were simulated by a constant current load resistance box and a power supply cabinet. The test platform is shown in Figure 11.

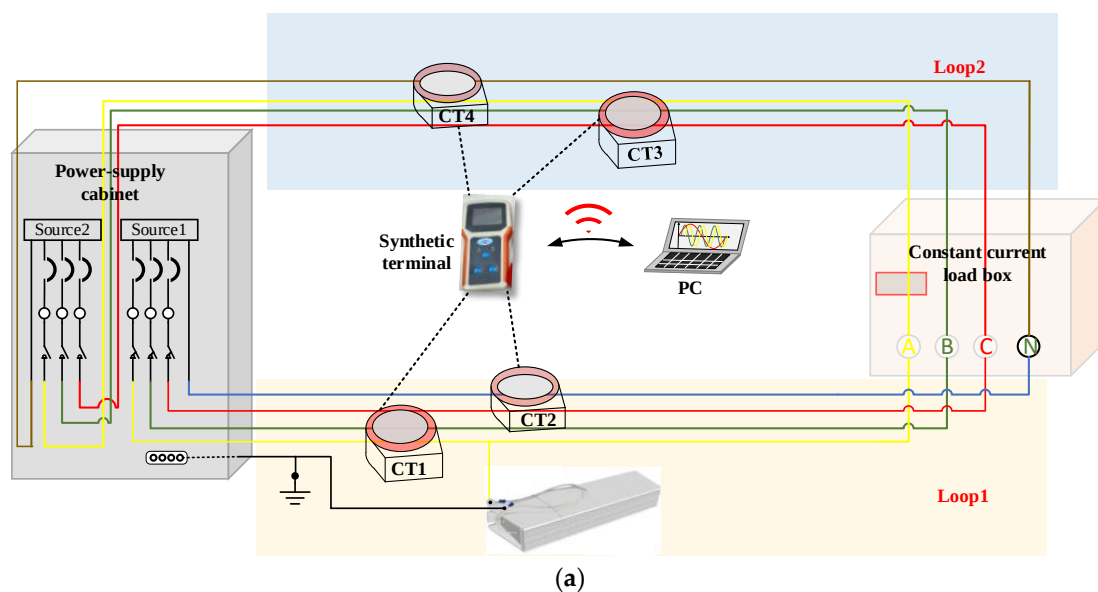


Figure 11. Cont.

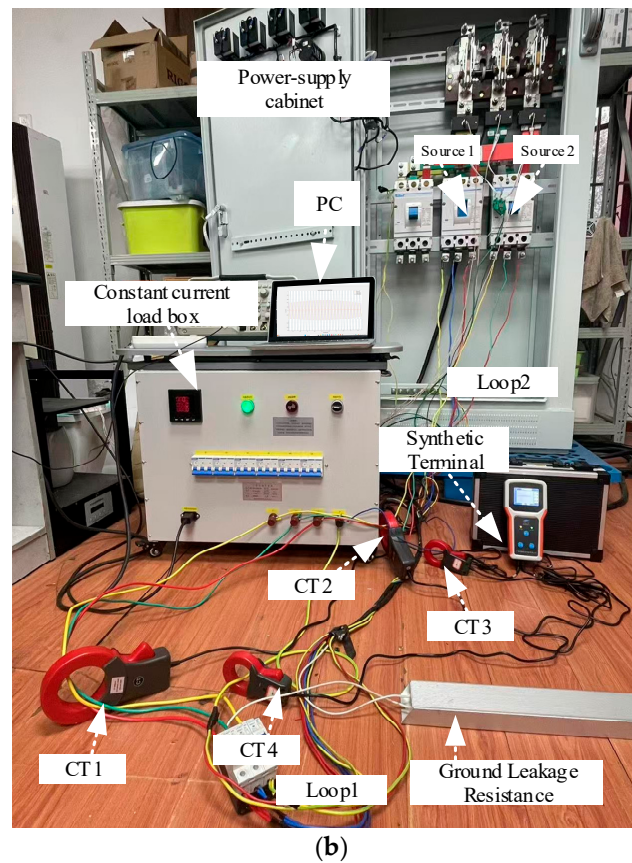


Figure 11. Test platform. (a) The schematic diagram of test wiring. (b) Laboratory test.

The power supply cabinet is used to simulate the main power source 1 and the standby power source 2 of the substation, which can generate a stable phase voltage of 220 V. The load in the resistance box is Y-connection, and the load current is adjustable from 0 to 30 A. Loop 1 and loop 2 are connected according to Figure 11a. CT1, CT2, CT3, and CT4 are used to collect the distributed current at the four nodes of A, B, C, and D. The distributed current is calculated and synthesized based on the synthetic terminal equipment. The collected data are transmitted to the PC through Wi-Fi communication between the terminal device and the PC for processing and analysis. In addition, the grounding leakage resistance with adjustable resistance value is connected to the three-phase outlet end of the power cabinet to simulate the aging of the cable.

5.2. Test of Power Cable Leakage Cable Measurement Method Based on Distributed Current Extraction

In this part, the proposed correlation current extraction method is tested to verify whether the proposed method can make a correct judgment on cable degradation. Similar to the simulation test in Section 4 Part A, the load box current I_{load} is changed to simulate different load power under real working conditions. By adjusting the resistance value of grounding leakage resistance, it is used to simulate different degrees of cable aging.

During the test, the load box current is continuously adjusted in the range of 0–30 A when the grounding leakage resistance is disconnected, and the leakage current value I'_s synthesized by the normal sensing system and the leakage current value I'_s synthesized by the abnormal sensing system are recorded. The data are shown in Figure 12a. In the case of load box current $I_{load} = 10$ A, the leakage resistance value R_0 is adjusted to 3–10 k Ω by using a precise sensor. The leakage current values I''_s synthesized by the terminal are recorded, and the data are shown in Figure 12b.

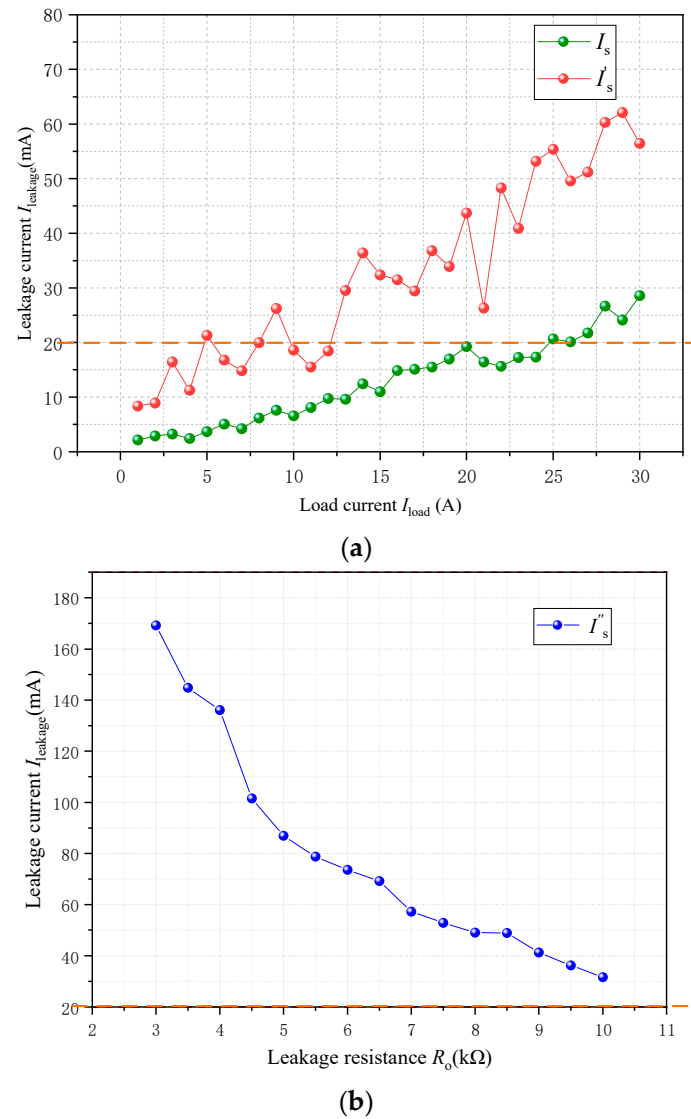


Figure 12. Leakage current I_s and I'_s in case (a): disconnected leakage resistance. Leakage current I''_s in case (b): varying leakage resistance.

It can be seen that when the load box current I_{load} changes continuously within 0~30 A, the maximum change amplitude of I_s measurement is 26.43 mA, and there is no obvious linear relationship. This change is introduced by the inherent error of the front-end transformer, power supply, and signal processing noise. This noise increases slightly with the increase in load current, but this does not affect the application of the proposed method in engineering practice. In field applications, after the equipment has been running normally for a period of time, twice the maximum value of the synthetic leakage current measured during the period can be used as the monitoring threshold to reduce the impact introduced by the inherent measurement error of the device.

When the ground leakage resistance changes from 3~10 k Ω , the maximum change amplitude of the leakage current value I_s reaches 137.6 mA and has an obvious linear relationship. It can be proved that the proposed phase current extraction method is sensitive to cable degradation. The results of the measurement using the inaccurate transformer rise with the increase in the load current I_{load} , and the maximum value reaches 62.1 mA, which is twice the normal operating value. It can be seen that, the larger the load current, the greater the noise introduced by the misaligned transformer, which will bring difficulties to monitoring.

5.3. Testing of Substation Power Cable Insulation Monitoring Method Based on Principal Component Analysis

Similar to the simulation settings, 500 sets of relevant current data were collected and recorded in normal operation, cable degradation, and transformer misalignment. The 500 sets of relevant current data in normal operation were used as the training set, and the 1000 sets of data in other cases were used as the test set. Hotelling's T^2 statistic in the principal component space and the Q statistic in the residual space were calculated respectively, and the threshold was determined according to the kernel function method. The results are shown in Figure 13.

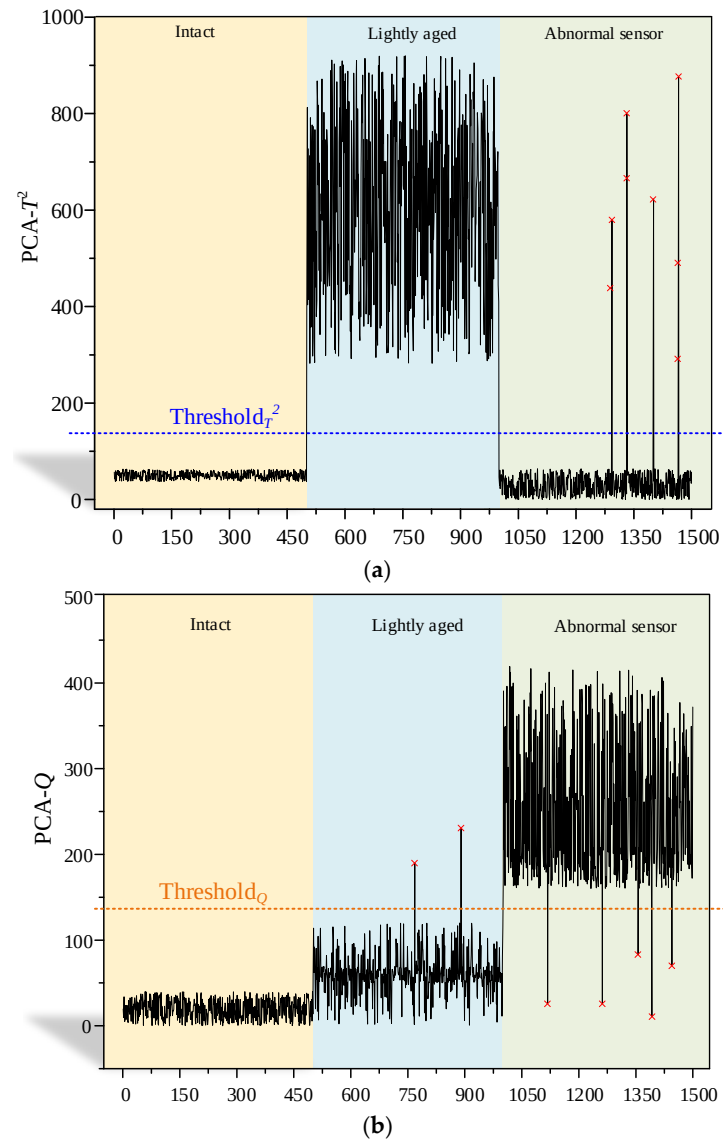


Figure 13. Analysis results of statistics of (a) T^2 and (b) Q .

The results in Figure 13 show that, in the principal component space, Hotelling's T^2 statistic will exceed the control limit only when the cable is degraded, but not when the sensor is inaccurate. Similarly, in the residual space, the Q statistic will exceed the control limit only when the transformer is inaccurate, but not when the cable is degraded. This result shows that the principal component analysis method can effectively identify the leakage current increase caused by line degradation and transformer inaccuracy and can be effectively used for insulation monitoring of power cables in substations.

6. Conclusions

This paper presented a new method for on-line insulation monitoring of power cables in substations. Aiming at the problems of neutral line shunting on the load side and the phase-to-neutral line physical space isolation in power cabinets, a leakage current measurement method of substation power cable based on distributed current extraction is proposed. In view of the serious influence of measurement error in distributed current synthesis, a method based on principal component analysis of distributed current is used to evaluate the insulation state of power cable in a substation. It can accurately evaluate the cable insulation while avoiding measurement errors. The main contributions of this paper are as follows.

- A power cable leakage current distribution model for the substation power supply system is established, and a quantitative relationship between leakage current and cable insulation state is derived through theoretical calculations. This analysis validates the theoretical feasibility of the proposed method. Based on this model, a new method for monitoring power cable leakage current in substations is presented.
- Considering the serious influence of measurement error on leakage current measurement, a method for evaluating the insulation state of power cables based on distributed current principal component analysis is proposed. By analyzing the T^2 statistics of the principal component subspace of the distributed current and the Q statistics of the residual subspace, the cable insulation state is separated from the measurement error. The on-line accurate monitoring of the insulation state of the power cable is realized, and the detailed process of the method is introduced.
- A simulation model of the distributed current principal component analysis method was built, and laboratory tests were carried out. The error rate of identifying the cause of leakage current increase is 1%. The effective evaluation of the insulation condition of power cables in substations has been successfully achieved, which provides a novel approach for monitoring the insulation status of power cables in substations.

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